TESTIMONY OF
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HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Estrella A. Seese, and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. What is your present position with the Company?

A. I am the Director of Pricing Division, Energy Services Department, Hawaiian Electric Company, Inc. My experience and educational background are listed in HECO-500.

Q. What is your area of responsibility in this proceeding?

A. I will be testifying for HECO, HELCO, and MECO (collectively the "Companies") and my testimony will cover the following areas relating to Issue No. 5 stated in the Commission's Prehearing Order No. 20922, concerning the appropriate rate design and cost allocation issues that must be considered with the deployment of distributed generation facilities:

1. ratemaking procedure and the Companies' cost-of-service study methodologies,
2. the Companies' rate design process and objectives, including the current rate structure, and
3. the appropriate rate design issues in deploying distributed generation.

RATEMAKING PROCEDURE AND COST-OF-SERVICE STUDY

Q. Please briefly describe the ratemaking procedure in Hawaii?

A. The utility ratemaking procedure in Hawaii is governed by the Commission's Rules of Practice and Procedure, Title 6, Chapter 61, §6-61-86 and §6-61-87. Any rate and tariff changes must be filed with, and approved by the Commission.

The steps in utility ratemaking are: (1) determination of the utility's revenue requirements or total costs of providing service; (2) preparation of cost of service study to allocate costs; and (3) rate design.

Q. What is a cost-of-service study?

A. A cost-of-service study is tool used to determine the cost responsibility of the different rate classes served by the utilities for ratemaking purposes. The Companies prepare two types of cost-of-service study for rate design and rate cases: (1) the embedded cost-of-service study, and (2) the marginal cost study. Although both studies address the utility's costs of providing service, the procedures and the emphasis of each of these two studies are different and independent from each other.

The embedded cost-of-service study is a tool or process used to categorize and allocate the utility's total revenue requirements of providing service among the various rate classes to determine each rate class's cost responsibility. The marginal cost study on the other hand, focuses on the measurement of the change in the total system costs due to a unit change in the utility's output in terms of kilowatt (kW), or kilowatthour (kWh) supplied by the utility, or of serving an additional customer.

Q. Why is the embedded cost-of-service study necessary for rate design purposes?

A. An embedded cost-of-service study is necessary since most of the utility plant facilities and services are shared by all the customers served by the system, and the costs of providing, operating and maintaining these facilities are incurred in total, and are neither separately recorded for each rate class or customer group, nor classified by the three parameters of cost causation generally used in designing rates. In order to design fair, reasonable and cost-based rates that will adequately produce the utility's revenue requirement, we need to know the cost responsibility of each of the rate classes. The embedded cost-of-service study provides the mechanism to systematically break down and allocate the total system costs, and provides a reasonable approximation of each rate class's fair share of the utility's costs of providing service.

The embedded cost-of-service study also provides unit demand-related cost, unit energy-related cost, and unit customer-related cost that serve as guidelines in setting the rate levels, as well as in determining the reasonableness of the rates. Pursuant to the Commission's Rules of Practice and Procedure, §6-61-87, utility ratemaking in Hawaii is based on embedded or accounting costs, rather than on marginal costs. The embedded cost-of-service study is the main basis of the Companies' rates.

Q. What costs are included in the embedded cost-of-service study?

A. The embedded cost-of-service study includes all the costs incurred by the utility in providing electric service to customers, including the operation and maintenance costs, depreciation expense, taxes, and return on capital. The summation of all these costs represents the utility's total revenue requirements.

Q. Will you briefly describe the general procedures used in an embedded cost-of-service study?

A. The embedded cost-of-service study includes three major steps in allocating the utility's total costs to the various rate classes:

1) Functionalization of costs into the major operating functions of production, transmission, and distribution of electric power. The production costs include all costs associated with the generation of power including fuel costs. The transmission costs include all costs associated with transferring

power from plants to substations or between switching stations at transmission voltage levels. The distribution function costs include costs associated with delivering power from transmission to distribution voltage levels and through the distribution system to the customer, including metering, customer accounting and billing.

2) Classification of the functionalized costs into demand-related costs, energy-related costs, and customer-related costs components, to facilitate allocation to the rate classes based on measurable service characteristics such as energy (kWh) consumption, or kW demand on the system.

Demand-related costs are costs incurred to serve the customers' kW demand on the system, such as the facilities' costs and the associated operation and maintenance costs. The energy-related costs include those costs that are incurred to produce the kWh energy used by customers, such as the fuel costs and purchased energy expense. The customer-related costs include those costs that are incurred in order to connect the customer to the system and maintain his account regardless of his/her energy (kWh) consumption or kW demand on the system. The customer-related costs may be viewed as consisting of plant-related and service-related customer costs. The plant-related customer costs include the customer cost component of the distribution lines and transformers, and the service drops and meters. The service-related customer costs are those that generally pertain to meter reading, customer billing and accounting and customer service-related activities.

3) Allocation of the three cost components to the various rate classes using the appropriate allocation bases such as kWh usage for energy-related

costs, kW demand for demand-related costs, and number and type of customers for customer-related costs.

Q. Will you briefly explain how each of the three major steps is developed?

A. Under the functionalization step, the recording of the accounting costs using the NARUC Uniform System of Accounts directly assigns certain costs items to the three functional categories. Some costs, such as those related to general plant and the administrative and general expense, are not recorded by functional accounts. These general type costs are indirectly categorized into the primary functions using an appropriate functionalization base determined by an analysis of the type and nature of these costs.

The classification of each functional cost into the three cost components of demand-related, energy-related, and customer-related costs is based on NARUC's Electricity Cost Allocation Manual. Following the NARUC cost classification rationale, the production costs are classified to demand and energy costs components; the transmission costs are classified to demand cost component; and the distribution costs are classified to demand and customer costs components.

After all the costs items have been functionalized and classified, each cost is then allocated to the different rate classes using an applicable allocation base. The energy-related costs are allocated based on the class's kWh usage. The customer-related costs are allocated on the basis of the number and type of customers. The demand-related costs are allocated on the basis of kW demand. However, unlike the energy costs and the customer costs, there are different measures of kW demand on the system – such as the system peak demand, class peaks, and noncoincident peak demand – which give rise to the different demand cost allocation methods. The cost of providing kilowatt is dependent not only on its magnitude but also on its time of occurrence in relation to the demands of the different customer classes served by the system giving rise to the different demand measures, and its allocation provokes the widest diversity of opinion on rate equitability.

Q. What demand costs allocation methods do the Companies use in their cost-of-service studies?

A. The Companies use the AED method to allocate the production and transmission demand-related costs, and the NCD method to allocate the distribution demand-related costs. These methods have been used in all of the Companies' prior rate cases, and have been found reasonable and approved by the Commission.

The AED Method considers several factors in allocating demand costs and results in relatively more stable results, unlike the other two major demand costs allocation methods which consider only one demand parameter in allocating demand costs. The AED Method considers the classes' demand requirements, energy consumption, and system load factor in allocating the demand costs. Given the Companies' system load profile with low seasonality and broad peak periods, the AED Method has proven to be reasonable for the companies.

The NCD Method is appropriate in allocating the distribution demand-related costs since the distribution facilities are generally sized to serve the maximum diversified demand at these service levels regardless of when the system peak or class' coincident peak loads occur.

Q. How does the embedded cost-of-service study determine cross-subsidies?

A. The Companies' embedded cost of service study prepared for rate case purposes provides the classes' rates of return at present rates and at proposed rates. The study also provides the classes' revenue requirements at the system average rate of return, which are generally defined as the classes' full cost of service. The difference between the classes' revenue requirements at the system average rate of return and the classes' revenues produced by the existing rates or by the proposed rates represents the subsidy. The inter-class subsidies embedded in the Companies' rates were provided in HECO Response to LOL-SOP-IR-70(c), and shown in HECO-501. As discussed later in my testimony, the cross-subsidies embedded in the Companies' rates are one of the significant rate design and cost allocation issues that must be considered with the deployment of distributed generation in Hawaii.

Q. Will the deployment of distributed generation result in changes to the Companies' embedded cost-of-service study methodology?

A. If and when the DG market develops significantly and to the extent that DG-related data are available, the Companies' embedded cost of service study may be expanded to include the DG customers as a separate class in the study. Additionally, depending on the DG market size and to the extent that data is available, the study may be expanded to reflect a more detailed breakdown of the generation, transmission, and distribution plant costs and associated operation and maintenance costs. These expansions in the embedded cost-of-service study will require more detailed cost information which is not presently available or easily determined. The benefits gained by such expansion should be balanced with the costs of developing and collecting the required data.

Q. How does the marginal cost study differ from the embedded cost-of-service study?

A. Unlike the embedded cost-of-service study whose end result is the allocation of the utility's total revenue requirements to the different rate classes, the marginal cost study measures the change in the utility's total costs associated with producing and distributing the additional kilowatt or kilowatthour, or of serving the additional customer on the system.

Like the embedded cost-of-service study, marginal costs are also categorized into the three cost components of demand-related, energy-related, and customer-related costs. The marginal demand costs include the generation, transmission, and distribution costs.

Q. What is the role of the Marginal Cost Study in ratemaking?

A. While ratemaking in Hawaii is based on embedded or accounting costs pursuant to the Commission's Rules of Practice and Procedure, §6-61-87, the Companies use marginal costs as one of the considerations in their rate design in accordance with the PUC Decision and Order No. 6696 in Docket No. 3874. The primary rationale for the use of marginal costs is that it results in an efficient allocation of resources by providing customers with the appropriate price signal. While there are merits to this argument, there are problems associated with the measurement and application of marginal costs in utility rate design that require careful consideration in its use as the sole basis of the Companies' rates.

RATE DESIGN

Q. What is rate design?

A. Rate design is the conversion or translation of the classes' revenue requirements resulting from the embedded cost-of-service study, into a pricing structure or rate structure to collect the utility's required revenues to cover its total cost of providing service. It is the process of putting the price tag to the electric service provided by the Companies.

Q. Will you describe the Companies' rate structure?

A. The Companies' current rate schedules include a residential rate schedule (Schedule R), the commercial rate Schedules G, J, H, U, P, PS, PP, and PT (for HELCO and MECO, the three Ps are still combined in one Schedule P), the public street lighting rate schedule (Schedule F), and the load management riders (Riders T, M, and I). The general rate elements included in the Companies' rate schedules include customer charges, energy charges, demand charges, and minimum charges. The commercial and industrial rate schedules may also include some provisions that reflect the differences in the services provided to different sub-groups within the rate schedule. For instance, the customer charge is differentiated between single-phase and three-phase service. The large commercial and industrial rate schedules (Schedule J and Schedule P) include provisions for service voltage adjustments.

The residential rate (Schedule R) and the small commercial rate schedule (Schedule G) are two-part rate structures consisting of a customer charge and an energy charge. The commercial and industrial rate schedules (Schedules H, J, U, P, PS, PP, and PT) are three-part rate form consisting of a customer charge, energy charges, and demand charges. The load management riders provide adjustments to Schedules J, P, PS, PP, or PT that provide incentives to large commercial and industrial customers to manage their load (i.e., load shifting) such as to help the utilities defer the need for future additional generation capacity.

The energy charge for the small general service (Schedules R, G, and H) is a single (flat) charge for all kilowatthours, while the energy charges for the large commercial and industrial customers (Schedules J, P, PS, PP, PT) as well as for the public street light service (Schedule F) are differentiated based on load factor blocks. The demand charge for Schedules J and H is a single (flat) charge for all billing kilowatt demand, while the demand charges for the large power service (Schedule P, PS, PP, and PT) are based on kilowatt blocks.

Q. Will you explain why the companies' load- factor block energy rate form in the current rates for commercial customers is appropriate with the deployment of distributed generation?

A. The load-factor block energy rate form reflects the interrelationship of kilowatthours usage and kilowatt demand. This rate form is widely used in the utility industry and generally applies to commercial and industrial service. The Companies' load-factor block rate form used in the energy charge for large commercial customers provides customers with strong incentives to reduce their peak demand and to manage their usage evenly throughout the day. It also encourages the more efficient use of the system facilities as reflected by the system load factor and in the system load profile.

The Companies' load-factor block energy rate form has been in effect for over 50 years. It's been used as a proxy for time-of-use pricing and reflects the costs differentials between on-peak and off-peak periods. The first 400 hours of use included in the first and second load factor blocks approximately reflect the Companies' on-peak period (14 hours per day, 30 days per month), while the last load factor block reflects the Companies' off-peak hours (10 hours per day, 30 days per month). For cost recovery consideration, the first 400 hours of use was broken down into two load factor blocks, and most of the fixed demand and customer costs that are not recovered from the demand and customer charges are embedded in the energy rate for the first load factor, since some customers may not go beyond the first load factor block. This cost recovery feature of the

Companies' load-factor block energy rate form is a mechanism for minimizing intra-class subsidy, and is appropriate with the deployment of distributed generation as DG customers are served under these schedules. Additionally, the use of load-factor block energy rate form as a proxy for time-of-use pricing provides similar price signals indicated by time-of-use rates but without the additional metering costs of implementing a mandatory time-of-use service for all large commercial customers.

Q. Please describe the Companies' rate design process.

A. The main basis of the Companies' rate design is the results of the embedded cost-of-service study which is based on the Companies total revenue requirements approved by the Commission. The Companies' rate design process takes into consideration the following:

1) rates must produce the Companies' total cost of providing service including an appropriate rate of return as reflected in the Companies' total revenue requirements approved by the Commission;
2) rates must be simple, easy to understand and implement;
3) rates must produce stable revenues and avoid rate shocks;
4) rates must encourage customer load management and efficient use of resources; and
5) rates must be fair, stable and equitable for all customers.

RATE DESIGN AND COST ALLOCATION ISSUES

Q. What are the rate design and cost allocation issues that must be considered with the deployment of distributed generation?

A. There are two major rate design and cost allocation issues that must be considered in deploying distributed generation, and the other issues generally result from these two main issues. The two main issues are:

1) the cross-subsidization between the rate classes; and
2) the recovery of a substantial portion of the Companies fixed costs in the energy charges.

Q. Please describe the subsidies embedded in the Companies' rates.

A. Cross-subsidy as reflected in the Companies' rates is defined as the difference between a class's total full cost of service and the total allocated class revenue requirements that the rates are designed to collect. The class's total full cost of service is defined as the class's total revenue requirements at system average rate of return. Overall, the commercial rate classes historically and currently subsidize the residential class. In other words, the allocated residential revenue requirements that the residential rates are designed to recover is and always has been lower than the residential class's total full costs of service. The difference between the residential class's total full costs of service and the revenues produced from the residential rates are recovered from the commercial rate classes. The subsidy to the residential class embedded in the commercial rate schedules ranges from $1.1M on Molokai to $21.1M on Oahu as shown in HECO-501.

Q. Will you discuss the costs recovered in each rate element?

A. As discussed earlier in my testimony, the embedded cost-of-service study which is the main basis of the Companies' rate design classifies the Companies' costs of providing service into the three cost components of: (1) demand-related costs, (2) energy-related costs, and (3) customer-related costs. Both the demand-related costs and the customer-related costs, also referred to as fixed costs, are incurred by the Companies regardless of the customers' energy consumption. For instance, if the customer reduces his/her kWh consumption, the Companies continue to incur the costs of operating and maintaining the plants and facilities required to serve the customer upon demand, and they continue to incur the costs of reading meters and billing the customer.

The small commercial service (Schedule G) includes a customer charge by service phase and a flat energy charge. Under the Schedule G rates, the flat energy charge recovers all of the energy-related and demand-related costs as well as the portion of the customer costs that are not recovered in the customer charge.

The large commercial and industrial power service (Schedule J, P, PS, PP, and PT) include a customer charge, demand charges based on kW demand blocks, and energy charges based on load-factor blocks. As in Schedule G, the energy charges under these rate schedules are designed to recover all of the energy-related costs and a significant portion of the demand-related costs as well as a portion of the customer-related costs that are not recovered in the demand and customer charges, respectively. The amount of fixed demand and customer costs recovered from the energy charges by rate schedule and by company are provided in HECO-502.

Q. Will you explain why considerations of the cross-subsidies embedded in the Companies' current effective rates and the recovery of fixed costs in the energy rates are important in deploying distributed generation?

A. The cross-subsidies embedded in the Companies' current effective rates, as well as the recovery of fixed costs in the energy rates are important considerations in deploying distributed generation for the following reasons:

1) The subsidies embedded in the Companies' rates are such that

substantial amounts of the total full costs of serving the residential class are recovered from commercial customers. The use of distributed generation by the commercial customers would result in lost kWh sales to the Companies. The lost of kWh sales from commercial customers impact the recovery of the residential costs of service that are embedded in, or subsidized by, the commercial rate schedules.

2) The lost kWh sales from the commercial customers resulting from the use of distributed generation also impact the recovery of significant portions of the fixed costs that are embedded in the energy charges of the commercial rate schedules.

The adverse impact of the lost kWh sales from commercial customers on the recovery of the Companies' fixed costs resulting from the use of distributed generation would increase rates to other ratepayers in the future. Depending on the DG market size, and the lost kWh sales, the future rate increase impact on other ratepayers could be significant. Thus, as competition spreads with the deployment of distribution generation, cross-subsidization becomes untenable.

Q. What are your recommendations regarding these two issues?

A. First of all, the various factors considered in the Companies' rate design process as noted earlier in my testimony remain the same. Some of these considerations however, may become more important than others with the deployment of distributed generation, and depending on the form of DG market that emerges as a result of this instant proceeding.

Revenue recovery and revenue stability are important considerations in keeping the Companies' financial integrity which benefits all ratepayers in the long run. As noted earlier, the use of distributed generation by commercial customers impact the Companies' revenue recovery and revenue stability due to the two issues of cross-subsidies embedded in the rates, and the recovery of fixed costs in the energy rates.

The Companies should be allowed to align the costs and the rates closer at much faster pace than allowed in the past rate cases, by limiting the subsidy to the residential class to some minimal amount or some minimal proportion than what is currently embedded in the companies' current effective rates, in the Companies' next rate cases. Additionally, significantly more of the fixed costs should be recovered in the demand charges and/or customer charges, and thereby aligns the rate elements closer to the costs components to provide more efficient pricing signal. Reducing or eliminating the cross-subsidies (between and within rate classes) will inevitably have different rate impacts on individual customers in the various rate classes.

Q. Is rate unbundling necessary to deploy distributed generation?

A. No. Rate unbundling is not necessary to deploy distributed generation. The unbundling of costs and rates was required by the unbundling of the functional services provided by the regulated vertically-integrated utilities such as the case in those jurisdictions that have mandated utility industry restructuring and deregulated power markets. This instant proceeding is not about deregulation or the unbundling of the functional services provided by the Companies. Additionally, wheeling is not within the scope of this proceeding as recognized by both the Consumer Advocate ("CA"), and The Gas Company ("TGC"). See CA Response to TGC/CA-SOP-IR-3(c), and TGC Response to LOL-SOP-IR-53.

Secondly, the Companies' cost-of-service study method already unbundle the total system costs or revenue requirements into the functional categories of generation, transmission, distribution, and customer service-related functions such as metering and customer-accounting and billing. The information required to further unbundle the costs of ancillary services is not available.

Thirdly, unbundling of rates is irrelevant because of the cross-subsidies embedded in the Companies' current rates. Unbundling of rates is useful only if they reflect the true costs of service.

Q. How do you define rates unbundling?

A. Unbundling of rates is the separation of the utility's rates by functional services such as generation, transmission, and distribution, and even ancillary services. The restructuring of the power market in some parts of the country beginning in the early 1980's resulted in the unbundling of the functional services that were traditionally provided by the regulated vertically-integrated power utilities. The utility generation function in these jurisdictions have been deregulated and opened to competition. The separation or unbundling of the functional services in these markets required the separation or unbundling of costs and charges for these services.

Q. What are the other rate design-related issues that must be considered in deploying distributed generation?

A. The other rate related issues pertinent to this case include the appropriate utility rates and charges and other service offerings to customers with existing distributed generation or considering using and installing distributed generation. These include standby charge and customer retention rate offerings.

STANDBY SERVICE

Q. Please describe the Companies' current standby service.

A. Customers who generate some or all of the electricity that they use generally want to purchase power from the Companies when their own generators or alternate suppliers are not running for any reason, to guarantee adequate and continuous supply of electricity. In general, these customers remain connected to the utility grid. HECO and MECO serve these customers under the standard commercial rate schedules (Schedules J, P, PS, PP, or PT), and there is no separate standby charge. HELCO serves these customers under the standard commercial rate schedules in conjunction with Rider A – Standby Service.

HELCO's Rider A was stipulated by the Consumer Advocate, and approved by the Commission after extensive review and revision, in its Decision & Order No. 18575 filed on June 1, 2001, in HELCO's last general rate proceeding, Docket No. 99-0207. It became effective on June 5, 2001 and applies to customers with regular alternate supplier of electricity other than the Company.

Q. Why does HELCO have a standby service provision?

A. A standby service provision was proposed on the Big Island because of HELCO's concern that application of its existing rate schedules to customers with on-site generation would not cover the cost of providing backup service to such customers. The goal in designing Rider A was to set fair and equitable rates that reasonably recover the costs of providing standby service from standby customers imposing such costs. The design of HELCO's Rider A was based on the following principles:

1. The standby service rates should be fair to the customers while reflecting the unique characteristics of the utility system, the costs of providing the service, the requirements placed on the utility system by the standby service customer, and the impacts on other customers.

2. Standby service rates should send proper price signals, such that economically efficient decisions on the part of self-generators to secure standby service result. Standby service rates should not encourage uneconomic bypass or encourage inefficient use of standby service to the detriment of other customers. Uneconomic bypass occurs when the cost of a customer's alternative source of electrical energy is lower than the cost of receiving service under HELCO's applicable standard rate schedule, but higher than HELCO's marginal cost of providing service. Due to the manner in which rates have been established in Hawaii, HELCO's rates for its large commercial customers are not only higher than HELCO's marginal costs, but also are higher than its average embedded costs of providing service to such customers.

It has been suggested that HELCO simply "repeal" Rider A. As indicated in its Rider A – Standby Service Report filed August 25, 2003, HELCO considered that option, but stated that Rider A should continue to apply to non-utility DG/CHP installations unless it is determined that that would be unfair after HELCO enters the CHP business on a regulated basis. In the CHP Program proceeding, Docket No. 03-0366, HELCO requested either (1) a finding that continued application of the standby service rider is fair in light of its proposed CHP pricing, or in the alternative (2) a determination that application of the standby service rider to non-utility DG/CHP installations should be made voluntary. If Rider A is modified to make it voluntary, current Rider A customers (as well as customers that have DG/CHP systems installed in the future) will have the opportunity to sign up for the Rider A option. If they do not elect to sign up for the Rider A option, they will not be subject to any Rider A charges, and will receive all service under the appropriate regular rate schedule. In the meantime, HELCO planned to consult with the Consumer Advocate as to its views on the continued fairness of the standby service rider, since HELCO and the Consumer Advocate stipulated to the form of the standby service rider approved by the Commission. (See also the response to HESS-SOP-IR-4 to HECO.)

If the Commission determines that Rider A should be made voluntary in order to alleviate concerns that Rider A will impede the efforts of competing suppliers of DG/CHP systems, then HELCO stated that it would file a revision to Rider A (using the 30-day notice provisions of HRS Section 269-16(b)) as soon as a determination has been made that HELCO will be permitted to provide CHP services to customers.

CUSTOMER RETENTION RATES

Q. You also mentioned customer retention rates as one of the rate related issues in the deployment of distributed generation. Will you explain the customer retention rates that the Companies currently have?

A. HECO and HELCO currently have the Rule 4, Sec. D which provides for Standard Form Contract for Customer Retention ("Rule 4 Rate Contract"). This rule provides specified rate discounts for Schedules J, P, PS, PP, and PT customers who have viable alternate energy suppliers other than the Companies. The energy rate discounts offered under the Rule 4 Rate Contract were set at amounts less than or equal to the percentage "subsidy" borne by the rate class. Thus, the rates (even with the discount) under the Rule 4 Rate Contact were still well above marginal costs. HECO currently does not have any Rule 4 Rate

Contacts. HELCO has a Rule 4 Rate Contract with the Hilton Waikoloa Village, effective December 10, 2001, Transmittal No. 02-01H, filed January 14, 2002. MECO has a service contract with Castle & Cooke, LLC, which was filed and approved in Docket No. 03-0261. See the response to LOL-SOP-IR-63, part d.

This customer retention rate provision was designed to retain loads (not customers) for recovery of fixed cost-related revenues. Its basis was provided in Docket No. 99-0106 for HECO, and Docket 99-0177 for HELCO, and in the interest of brevity, will not be repeated here. (See also the Companies response to the Informal Complaint No. IC-03-098, filed August 5, 2003, Part I, Appendix A, pages 5-6, and the CHP Program application, Exhibit C, page 5, footnote 3, Docket No. 03-0366.)

Q. Was the Rule 4 Rate Contract developed before the Companies developed their CHP Program?

A. Yes. The Rule 4 Rate Contract was developed in 1999 timeframe, and the Companies' approach to DG/CHP has evolved since that timeframe. See Exhibit C of the CHP Program Application, Docket No. 03-0366.

Q. What is HECO and HELCO's current position on the Rule 4 Rate Contract?

A. In light of the filing of the Companies' CHP Program application on October 10, 2003, Docket No. 03-0366, and the evolution of the Companies' approach to DG/CHP, HECO and HELCO are in the process of reevaluating the applicability of the Rule 4 Rate Contract.

SCHEDULE CHP

Q. Will you briefly describe the Companies' proposed Schedule CHP filed in Docket No. 03-0366?

A. On October 10, 2003, the Companies filed the proposed CHP Program for Commission approval in Docket No. 03-0366. Included in the Companies' proposed CHP Program is the proposed Schedule CHP which is the tariff provision that would be applicable to customers participating in the CHP program.

The proposed Scheduled CHP provides the rates, terms and conditions, eligibility criteria, and standard agreement form for the proposed CHP Program. The Availability Clause provides the qualifying power load and thermal energy load threshold levels. The Schedule CHP's rate elements are adjustments to the applicable rate schedule and include the following:

1) Energy Rate Discount applied to the kWh supplied by the CHP unit, subject to a minimum guaranteed discount based on 85% availability of the CHP unit;
2) Facilities Charge by chiller size which applies to participating customers' requesting and requiring absorption chillers and cooling towers to be included in the CHP unit;
3) Base Thermal Charge for the thermal energy supplied by the CHP unit which is used as a "benchmark" for the effective thermal charge which will be determined contractually based on the characteristics of the particular CHP installation; and
4) Termination Charge determined on contract basis.

The determination of these rate elements is provided in the Companies' CHP Program application filed in Docket No. 03-0366, and in the interest of brevity, will not be repeated here.

Q. What are the costs of the Companies' proposed CHP Program?

A. The costs of the proposed CHP Program are identified in the Companies' program application beginning on page 7, and include: (1) the installed costs of the CHP systems; (2) the associated operation and maintenance costs of the systems including the systems' fuel costs; and (3) the program administration and marketing, as well as the energy rate discount provided in the proposed Schedule CHP.

Q. How did the Companies determine the proposed rates and charges for their CHP Program?

A. The participants in the Companies' proposed CHP Program will be served under the applicable rate schedule in conjunction with the proposed Schedule CHP. As indicated earlier, the proposed Schedule CHP includes an energy rate decrease applied to kWh supplied by the utility-owned CHP system, a facilities charge applied to customers requiring and requesting absorption chillers, and a thermal charge for the thermal load supplied by the CHP system. The determination of the proposed Schedule CHP rates and charges is discussed in detail in the Companies' CHP Program application in Docket No. 03-0366, beginning on page 22, and will not be restated here.

SUMMARY

Q. Please summarize your testimony.

A. My testimony addresses the Issue No. 5 in the Commission's Prehearing Order No. 20922, concerning the appropriate rate design and cost allocation issues that must be considered with the deployment of distributed generation in Hawaii. The two main rate-related issues that must be considered in this instant proceeding are the cross subsidies embedded in the Companies' current effective rates and the recovery of fixed costs in the energy rates. These two issues are important in deploying distributed generation as they impact the Companies' revenue recovery and financial integrity that could have future adverse rate impacts on all ratepayers.

My testimony also presented the Companies' position on these issues as well as on other rate related issues, including HELCO's current Rider A – Standby Charge, HECO's and HELCO's standard customer retention discount provided in Rule 4, the Companies' proposed Schedule CHP, and the relevance of rates unbundling in this instant proceeding.

Q. Does this conclude your testimony?

A. Yes.